REBUTTAL TESTIMONY
OF
JOSEPH M. LYNCH
ON BEHALF OF
SOUTH CAROLINA ELECTRIC & GAS COMPANY
DOCKET NO. 2018-2-E

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Joseph M. Lynch, and my business address is 220 Operation Way, Cayce, South Carolina.

Q. ARE YOU THE SAME JOSEPH LYNCH WHO HAS PREVIOUSLY FILED TESTIMONY IN THIS DOCKET?

A. Yes.

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. The purpose of my rebuttal testimony is to discuss South Carolina Electric & Gas Company's ("SCE&G" or the "Company") response to the direct testimony of 1) Mr. Brian Horii filed on behalf of the South Carolina Office of Regulatory Staff ("ORS"); 2) Ms. Devi Glick filed on behalf of the South Carolina Coastal Conservation League ("CCL") and the Southern Alliance for Clean Energy ("SACE"); and 3) Dr. Ben Johnson filed on behalf of the South Carolina Solar Business Alliance, LLC. ("SCSBA").

REBUTTAL TO TESTIMONY OF MR. BRIAN HORII

Q. WITH RESPECT TO MR. HORII'S TESTIMONY, PLEASE EXPLAIN HOW YOU ORGANIZE YOUR RESPONSES.

A. My rebuttal testimony sequentially addresses the issues raised by Mr. Horii as they appear in his direct testimony.

Q. ON PAGE 8, LINES 6 THROUGH 7, MR. HORII CLAIMS SCE&G IS IMPLEMENTING "A DRAMATIC CHANGE IN APPROACH." DO YOU AGREE?

A. No. SCE&G is using the same difference in revenue requirements ("DRR") methodology previously approved by the Commission.

Q. SCE&G IS PROPOSING A ZERO AVOIDED CAPACITY COST FOR ITS PR-2 RATE. WHY IS THAT NOT CONSIDERED A SIGNIFICANT CHANGE?

A. It is a change in result, not a change in methodology and this result should have been expected. The "dramatic" change this year actually is the significant increase in new solar capacity with signed Power Purchase Agreements ("PPAs") since the Company's last fuel proceeding and this "dramatic" change in circumstances is the primary cause of the change in result. There are 865 MWs of capacity currently under contract. As Company Witness John Raftery states in his direct testimony, this represents approximately 17% of SCE&G's 2018 forecasted system peak demand of 5,077 MW.

Q. WHY DO YOU SAY THAT THIS RESULT OF A ZERO AVOIDED CAPACITY COST SHOULD BE EXPECTED?

A. The economic principle is known as the "Law of Diminishing Marginal Returns." As more and more of a product is added, the usefulness or value of each successive addition decreases. In addition to the 865 MW of solar currently under contract, there is approximately another 800 MWs in some stage of negotiations. The interconnection queue for SCE&G's system also currently consists of 183 active projects that would add a total of 5,285 MWs of additional solar capacity. Based on the Law of Diminishing Marginal Returns, it is logical that there is a zero point of value somewhere along this continuum to 5,285 MWs. The avoided energy costs are by far the larger component of avoided costs and, using last year's PR-2 rate and avoided cost, only about 5% of the avoided cost is related to capacity. As more and more solar comes onto the system, the avoided capacity value would reach zero well before the energy value diminishes to this point. With 865 MWs under contract, SCE&G therefore contends that solar has already reached this zero point for capacity.

Q. ON PAGE 9, LINE 2, MR. HORII CLAIMS THAT SCE&G "HAS NOT ADEQUATELY DEMONSTRATED THAT WINTER CAPACITY NEEDS ARE THE SAME OR GREATER THAN SUMMER CAPACITY NEEDS." DO YOU AGREE?

A. No. Exhibit No. ___ (JML-1) to my direct testimony contains all of the information necessary to demonstrate that SCE&G's capacity needs are greater in the winter than in the summer. In addition, the following table highlights the Company's relative need for capacity in summer and winter. This calculation of the future need for capacity is based on the summer and winter peak demand forecast offset by existing demand side management ("DSM"), existing signed PPAs with solar qualifying facilities ("QFs"), and existing generating capacity. The other elements in the resource plan not reflected in this calculation represent a plan of how SCE&G might meet the future capacity need.

	2019	
	Summer	Winter
Peak Demand MWs	5,111	5,071
Reserve Margin	14%	21%
Total Capacity Need	5,827	6,136
Less DSM	-275	-223
Less Solar	-162	0
Less Existing Capacity 2018(S)	-5,278	-5,278
Less Extra Winter Capacity	0	-186
Net Incremental Need	112	449
Difference in Winter-Summer Need		337

Thus, the seasonal peak demand forecasts and the seasonal reserve margins show that SCE&G's incremental capacity need is 112 MWs in the summer and 449 MWs in the winter.

Q. MR. HORII ARGUES THAT THE WINTER RESERVE MARGIN SHOULD BE 18%. WOULD USING HIS ESTIMATE CHANGE THE CONCLUSION?

A. No. The same calculations are shown in the following table using a winter reserve margin of 18%.

	2019	
	Summer	Winter
Peak Demand MWs	5,111	5,071
Reserve Margin	14%	18%
Total Capacity Need	5,827	5,984
Less DSM	-275	-223
Less Solar	-162	0
Less Existing Capacity 2018(S)	-5,278	-5,278
Less Extra Winter Capacity	0	-186
Net Incremental Need	112	297
Difference in Winter-Summer Need		185

Even assuming Mr. Horii's suggested 18% winter reserve margin, which, as I will discuss below, results from an error in his calculations, the 2019 winter need for capacity is 185 MW greater than the summer need.

Q. HAVE YOU MADE THIS CALCULATION FOR ALL THE YEARS IN THE IRP PLANNING HORIZON?

A. Yes. The following table compares the results using a winter reserve margin of 21% to that of 18%.

	21%			18%		
Year	Summer	Winter	Difference	Summer	Winter	Difference
2019	112	449	337	112	297	185
2020	48	504	455	48	350	302
2021	131	586	455	131	430	300
2022	250	636	385	250	479	229
2023	341	670	329	341	512	171
2024	409	720	310	409	561	151
2025	486	777	291	486	616	131
2026	561	829	268	561	667	106
2027	627	878	251	627	715	88
2028	688	926	238	688	762	74
2029	745	970	225	745	805	59
2030	797	1,021	224	797	854	58
2031	854	1,071	217	854	903	49
2032	909	1,122	213	909	953	44

Again, even assuming a winter reserve margin of 18%, there is a greater capacity need in winter than summer.

Q. ON PAGE 10, LINE 4, MR. HORII CLAIMS THAT THERE ARE "FLAWS AND INCONSISTENCIES" IN SCE&G'S 2017 RESERVE MARGIN STUDY AND, ON LINE 7, HE CLAIMS THAT SCE&G DID NOT PROVIDE DATA TO SUBSTANTIATE ITS CALCULATIONS IN RESPONSE TO A DATA REQUEST. DO YOU AGREE?

A. No. As I discuss below, there are no flaws or inconsistencies in the Reserve Margin Study. Furthermore, SCE&G appropriately responded to each data request submitted by ORS and provided an electronic version of all data necessary to reproduce the regression equations documented in the studies attached to my prefiled direct testimony. I am not aware that ORS requested or required any additional information from the Company, or that ORS notified SCE&G that the information provided was not adequate for its needs. In addition, I note that on page 10, lines 5 through 7, of Mr. Horii's prefiled direct testimony, he acknowledges that the Company informed him of the difference in the data used during a conversation he requested with SCE&G.

Q. ON PAGE 10, LINE 22, THROUGH PAGE 11, LINE 2, MR. HORII SAYS "THE COMPANY IS FORECASTING SUMMER AND WINTER PEAK DEMANDS FOR FUTURE YEARS IN AN INCONSISTENT MANNER THAT CREATES A POTENTIALLY FALSE INDICATION OF HIGHER CAPACITY NEED FOR THE WINTER SEASON." IS HE CORRECT?

A. No. The easiest way to demonstrate that there is no bias towards a larger winter peak forecast is to compare the growth projections for each season. The growth rate for the summer peak projections for years 2018 through 2032 is 1.14% and for the winter, the growth rate is 0.83%. Since the growth in the number of customers and their kWh energy consumption are the primary drivers for the summer and winter peak demands, it is natural that they would grow at the same rate. However, the Company believes that residential and commercial customers have been changing their usage to conserve energy in years when economic conditions are challenging, but that, as the economy improves there will be less conservation. This would affect the summer peak demand but, because the winter peak is significantly affected by energy consumed by heating strips, the winter peak will be little affected by conservation.

Q. ON PAGE 11, LINES 12 THROUGH 14, MR. HORII REPORTS THAT SCE&G'S METHODOLOGY IS NOT AN INDUSTRY STANDARD APPROACH "SUCH AS THE LOSS OF LOAD PROBABILITY METHOD PRESENTED BY SCE&G IN ITS PRIOR 2012 RESERVE MARGIN STUDY." DID SCE&G USE THE LOSS OF LOAD PROBABILITY METHOD IN 2012?

A. No. SCE&G has never used the Loss of Load Probability method, also referred to as Loss of Load Expectation ("LOLE") method, to determine an appropriate reserve margin. The Company believes that the LOLE method does not adequately address the summer and winter peak demand risk faced by SCE&G. Instead, for at least 20 years, SCE&G has used what it calls the component methodology in which the three components of reserves are addressed directly. Two of these components relate directly to risk, i.e., demand side risk and supply side risk. The third component of reserves represents SCE&G's obligation under the VACAR reserve sharing arrangement. However, in recent IRPs, SCE&G has reported the results of its LOLE calculation only for the purpose of providing another data point to support its 14% summer reserve margin. Importantly, using the standard industry target for having an LOLE of 1 day of outage in 10 years, the LOLE methodology would suggest the need for SCE&G's reserve margins to be 23.5%, 23.5%, 23.5%, 23.3%, and 24.1% as reported in the 2013 through 2017 IRPs respectively.

Q. ON PAGE 14, LINES 4 THROUGH 11, MR. HORII ARGUES THAT THE WINTER REGRESSION EQUATION HAS AN UPWARD CURVE "WHICH IS COUNTER TO ENGINEERING-BASED EXPECTATIONS," THAT THIS "CAN RESULT IN AN OVERLY LARGE ESTIMATE OF WINTER VARIABILITY," AND THAT THE SUMMER SHAPE WHICH IS CURVED DOWN "IS WHAT I WOULD EXPECT." IS THIS A CONCERN?

A. No. In the summer, one would expect the shape of the regression line to curve down because during very hot hours in the summer, air conditioners and heat pumps (which in the summer are in cooling mode) in most homes stop cycling and instead run continually. As the hours become even hotter, the increase in load slows because many air conditioners cannot use more power regardless of further increases to the temperature, i.e., the units stop cycling. The winter, however, presents a different problem. Many SCE&G customers have heat pumps, which use heat strips as supplemental heating to warm residences and businesses in very cold weather. Most standard heat pumps have one bank of heat strips rated at 5 kW, but some have multiple banks of heat strips that can be rated from 5 kW to 15 kW. These heat strips, which use very inefficient resistant heating, do not experience a similar saturation point like the air conditioning cycle does in the summer. Additionally, some customers use space heaters to supplement the heating in their homes and businesses, which is an extremely inefficient heating source. All this suggests that an upward curving load curve in the winter is reasonable.

Q. DO YOU TAKE INTO CONSIDERATION THE CURVATURE OF THE LINE WHEN ESTIMATING THESE REGRESSION EQUATIONS?

A. No. The data determines the shape. Even so, I considered the fact that the weather effect on load might not be linear and might change as the weather became more extreme and, therefore, I estimated a quadratic regression equation. The coefficient of the squared term determines whether the parabola will curve upward or downward. A positive coefficient for the squared term results in an upward curving parabola while a negative squared term results in a downward curving parabola. The least squares estimation process determines the result based on the data. For the summer model shown on page 12 of Exhibit No. ___ (JML-2) attached to my direct testimony, the coefficient of the squared term is -2.0614, a negative number, which means a downward sloping curve. The coefficient of the squared term in the winter model shown on page 13 of Exhibit No. ___ (JML-2) is 1.3999, a positive number, which means an upward sloping curve. Note also that both squared coefficients are statistically significant in their respective models.

Q. WOULD A LINEAR REGRESSION EQUATION TO MEASURE THE WEATHER EFFECT ON LOAD BE AS USEFUL AS THE NON-LINEAR QUADRATIC APPROACH THAT SCE&G USED?

A. No. As reflected on page 14, line 4, of his direct testimony, even Mr. Horii states that the downward sloping summer curve is to be expected. However, he does not accept the upward sloping winter shape, which I believe to be reasonable. While the winter shape is upward sloping, it is a very gradual incline over the values of heating degree days experienced. Exhibit No. ___ (JML-5) attached to my rebuttal testimony contains a graph of the winter shape restricted to heating degree days greater than 200 where the vertical axis begins at zero. The curve over these values of heating degree days is very close to linear—so much so that a linear equation, such as the one used by Mr. Horii, should not produce significantly different results.

Q. DID YOU FIND ANY ERRORS IN MR. HORII'S WORK?

A. Yes, I did. Mr. Horii miscalculated the maximum possible winter peak demand.

Q. PLEASE EXPLAIN WHY THIS IS AN IMPORTANT ISSUE.

A. Mr. Horii asserts that SCE&G has overstated its demand side risk in winter thereby incorrectly creating a capacity need that is higher in the winter than in the summer. From this overstatement, Mr. Horii asserts that SCE&G then derived a zero capacity value for incremental solar because solar has no capacity value in serving winter peak demands.

Q. WHAT WAS THE ERROR THAT MR. HORII MADE?

A. On page 16, Table 3 of his direct testimony, Mr. Horii presents the results of his winter load analysis, which I have reprinted below:

Table 3: Winter Demand Side Risk

MW Peak Demand - Winter				
	Maximum	Normal	Deviation	%Deviation
SCE&G JML-2, Table 1	5172	4630	542	11.7%
E3	5087	4662	425	9.1%

Page 17, Table 4, of his direct testimony also reflects information from which I am able to determine the regression equation he used to develop his calculations. The left side of the following table shows the portion of Mr. Horii's Table 4 which contains his regression results. The right side of the following table is an algebraic formulation of those results that I will use to explain the error.

Image from Mr. Horii's Table 4		**Algebraic Formulation of Regression Results**
	Coefficients	**Maximum Load = 1747.3**
Intercept	1747.325757	
ihol	-647.1513228	**-647.15 * ihol** (=1 if holiday, =0 otherwise)
wkend	-436.1093908	**-436.11 * wkend** (=1 if weekend, =0 otherwise)
hdh	9.390656604	**+ 9.391 * hdh**
Jan	109.0530828	**+ 109.05 * Jan** (=1 if January, =0 otherwise)
Feb	154.3791379	**+ 154.38 * Feb** (=1 if February, =0 otherwise)
Nov	-141.8875	**- 141.89 * Nov** (=1 if November, =0 otherwise)

Using Mr. Horii's regression equation and the maximum heating degree days of 344, I am able to recreate his maximum demand calculations. For example, assuming the peak were to occur in January:

$$\text{Maximum Load} = 1{,}747.32 + 9.391 \times \text{hdh} + \text{Jan}$$

$$\text{Maximum Load} = 1{,}747.32 + 9.391 \times 344 + 109.05 = 5{,}086.9 = 5{,}087.$$

However, history shows that the maximum winter demand on SCE&G's system does not only occur in January, but also occurs in February. Using Mr. Horii's same regression equation, but assuming a February peak, produces a higher maximum load:

Maximum Load = 1,747.32 + 9.391 × hdh + Feb

Maximum Load = 1,747.32 + 9.391 × 344 + 154.38 = 5,132.2 = 5,132.

Because this maximum load is higher than the January load, it is more appropriate to use a February peak to calculate the maximum winter demand. Simply correcting for this error increases the deviation in Mr. Horii's table by 45 MW resulting in a total deviation of 470 MWs (5,132 MW – 4,662 MW) which is closer to my calculated deviation of 542 MWs.

Q. IF MR. HORII WERE TO USE THE FEBRUARY PEAK, WOULD IT NOT ALSO BE APPROPRIATE TO CHANGE THE MONTH TO CALCULATE NORMAL LOAD TO FEBRUARY AS WELL?

No. First, it is not correct to choose a particular month to calculate normal load. Instead, normal load should be calculated based on a historical average of system peaks, which would include peaks occurring in both January and February. By comparison, when calculating maximum peak, it is appropriate to use February since that month gives the largest estimate of load.

Q. DID YOU MAKE THE CORRECT CALCULATIONS USING MR. HORII'S LINEAR MODEL?

A. Yes. Exhibit No. ___ (JML-6) shows my estimate of the equations. Comparing these estimates to Mr. Horii's results on page 17 shows that both estimate the same equations, i.e., all corresponding statistical parameters are equal. Exhibit No. ___ (JML-7) shows the date of SCE&G's historical winter peak, the heating degree hours for that morning and the estimated peak demand based on Mr.

Horii's linear model. For example, row 6 shows the maximum number of heating degree days of 344, which occurred on February 5, 1996. If that weather occurred today, Mr. Horii's linear regression equation would estimate the resulting winter peak demand to be 5,132 MWs, which is the same number I calculated above. Using the average of these 27 estimated peak values produces a peak load estimate under normal or average conditions. The table below updates Mr. Horii's Table 3 and demonstrates that the two estimates of winter variability are comparable.

E3 Table 3 Updated: Winter Demand Side Risk				
	Maximum	Normal	Deviation	%Deviation
SCE&G JML-2, Table 1	5172	4630	542	11.7%
E3 Updated	5132	4656	476	10.2%

Q. IF THE CHOICE IS BETWEEN SCE&G'S QUADRATIC ESTIMATE FOR WINTER DEMAND VARIABILITY OF 542 MWS AND E3'S LINEAR CORRECTED ESTIMATE OF 476 MWS, CAN YOU EXPLAIN WHY YOUR METHOD IS APPROPRIATE?

A. Yes. First, it is important to keep in mind that there are few absolutes in statistics. Since both models can be estimated, however, it is possible to generate confidence intervals for each model. The following table shows the point estimate for the winter peak demand calculated using both models as well as a 95% confidence interval around the regression mean implied by each of the models.

Maximum Peak Demand Estimates With 95% Confidence Interval (MWs)			
	Point Estimate	Lower Bound	Upper Bound
SCE&G's Quadratic Equation	5172	5043	5301
E3's Linear Equation	5132	4982	5282

Q. WHAT DO YOU CONCLUDE FROM THE ANALYSIS USING CONFIDENCE INTERVALS?

A. Since SCE&G's estimate of the peak demand falls within the 95% confidence interval derived from E3's linear equation model, SCE&G's estimate is not statistically different from E3's results and therefore should be considered a reasonable estimate.

Q. ON PAGE 19, LINE 10, MR. HORII CLAIMS THAT SCE&G'S GROSS PEAK DEMAND FORECASTS "ARE HIGHER THAN WHAT NORMAL LOADS SHOULD BE GIVEN TYPICAL 1% PER YEAR GROWTH RATES SINCE 2016." IS SCE&G'S PEAK DEMAND FORECAST TOO HIGH?

A. No. Recent experience shows that SCE&G's peak demand forecasting is reasonable. The following table compares the one year ahead peak demand forecast with the actual peaks experienced each year since the Great Recession of 2008-2009.

	Summer			Winter		
Year	Forecast	Actual	Diff.	Forecast	Actual	Diff.
2010	4752	4735	17	4119	4868	-749
2011	4726	4885	-159	4501	4397	104
2012	4750	4761	-11	4660	3984	676
2013	4778	4574	204	4491	4853	-362
2014	4786	4594	192	4496	4970	-474
2015	4747	4750	-3	4602	4409	193
2016	4766	4807	-41	4531	4457	74
2017	4805	4701	104	4636	4768	-132
	Average Over-forecast		38	Average Under-forecast		-84

This table shows that, on average, annual summer peak demand is over-forecasted by 38 MWs and annual winter peak demand is under-forecasted by -84 MWs. The table also shows that in half of the years the forecast was high and in half of the years the forecast was low in both the summer and winter seasons.

It also is important to remember that SCE&G has access to a significant amount of demand response. Exhibit No. ___ (JML-1) attached to my direct testimony shows that the demand response resource in the 2018 summer is 274 MWs and in winter 222 MWs. Therefore, the firm peak demand forecast is 4,803 MWs for 2018 summer and 4,802 MWs for 2018 winter. These firm peak forecasts are reasonable compared to the actual peak demands, especially considering that SCE&G would employ its demand response resources on many of these historical peak days.

Q. ON PAGE 22, LINES 1 THROUGH 2, MR. HORII CLAIMS THAT "SCE&G HAS NOT PROVIDED A LONG-RUN AVOIDED CAPACITY COST IN THIS DOCKET." DO YOU AGREE?

A. No. Using its DRR methodology, SCE&G provided a long-run avoided capacity cost for solar QFs, which is zero. As I stated in my direct testimony, if incremental solar QF purchases do not change the resource plan, then the capacity cost that would be avoided by that purchase is zero.

Q. ON PAGE 22, LINES 10 THROUGH 11, MR. HORII RECOMMENDS THAT "THE CURRENT CAPACITY VALUE BE MAINTAINED FOR BOTH PR-1 AND PR-2." DO YOU AGREE?

A. No. Adding a capacity payment to PR-1 and PR-2 when there are no associated avoided capacity costs would contravene PURPA regulations, which provide that "[n]othing … requires any electric utility to pay more than the avoided costs for purchases" from QFs. 18 C.F.R. § 292.304(a)(2). While these payments represent a pass through of costs and would be recoverable through SCE&G's fuel clause, SCE&G's customers ultimately would pay more for this purchased power than PURPA intends.

Q. ON PAGE 22, LINES 14 THROUGH 19, MR. HORII RECOMMENDS THAT SCE&G PROVIDE A PR-2 RATE FOR NON-SOLAR RESOURCES. DO YOU AGREE?

A. No. Since there are no non-solar QFs currently seeking a PPA, SCE&G contends there is no need for such a published tariff. Should a non-solar QF desire to enter into a PPA, SCE&G will negotiate a contract with that party. If, in the future, a substantial number of non-solar QFs desire to interconnect with the Company's system, as has been the case with solar QFs, SCE&G then would consider developing a published tariff. This approach has worked satisfactorily for SCE&G since PURPA was passed and only when the number of solar PPA applications significantly increased did the Company believe it would be more efficient to have a separate published rate for these QFs.

<u>REBUTTAL TO TESTIMONY OF MS. DEVI GLICK</u>

Q. WITH RESPECT TO MS. GLICK'S TESTIMONY, PLEASE EXPLAIN HOW YOU ORGANIZE YOUR RESPONSES.

A. In the same manner I responded to Mr. Horii's testimony, my rebuttal testimony sequentially addresses the issues raised by Ms. Glick as they appear in her direct testimony. I also would note that Ms. Glick's testimony appears to primarily restate suggestions and recommendations that CCL and SACE made in the 2015 Net Energy Metering Docket No. 2015-205-E and in the Company's 2016 and 2017 fuel proceedings, Docket Nos. 2016-2-E and 2017-2-E, and which were rejected by the Commission in Commission Order No. 2017-246.

Q. PAGE 3, LINES 13 THROUGH 17, MS. GLICK CLAIMS THAT "SCE&G NOW PROPOSES SUBSTANTIAL CHANGES TO THE AVOIDED COST METHODOLOGY" AND ON PAGE 7, LINE 12 THAT SCE&G DID NOT USE THE METHODOLOGY APPROVED BY THE COMMISSION. DO YOU AGREE?

A. No. For the same reasons set forth on pages 2-3 above, SCE&G is using the same methodology as in previous years and as approved by the Commission

Q. PAGE 9, LINES 6 THROUGH 10, MS. GLICK CLAIMS THAT SCE&G "HAS HISTORICALLY USED A 14 PERCENT WINTER RESERVE MARGIN" AND "HAS INCREASED ITS WINTER RESERVE MARGIN TO 21 PERCENT, A 50 PERCENT INCREASE." DO YOU AGREE?

A. No. Until this year, SCE&G has never had a winter reserve margin and instead only had a summer reserve margin.

Q. ON PAGE 9, LINE 11 AND ELSEWHERE, MS. GLICK DISCUSSES THE RESERVE MARGINS OF SCE&G'S PEERS. FOR EXAMPLE, SHE STATES THAT DUKE ENERGY AND SOUTHERN COMPANY BOTH HAVE A 17% RESERVE MARGIN. IS SCE&G'S 21% WINTER RESERVE MARGIN UNREASONABLE IN COMPARISON?

A. No. First, I would point out that PJM has a 16% summer reserve margin and a 27% winter reserve margin, both of which are greater than SCE&G's. Florida electric utilities also plan to a 20% reserve margin, which likely refers to a summer reserve margin. However, SCE&G's demand side risk is greater in winter than summer. As my methodology and that of Mr. Horii's reflects, SCE&G's winter peak can increase approximately 500 MWs due to abnormal winter weather. The summer peak weather risk of 200 MWs reflects a 300 MW difference between summer and winter, and a peak demand of approximately 5,000 MWs reflects the need for at least a 6% increase in reserve margin, winter over summer. If the summer reserve margin is 14%, the winter reserve margin therefore should be at least 6% higher or at least 20%. Accordingly, SCE&G's 21% winter reserve margin is very reasonable.

Q. ON PAGE 10, LINES 9 THROUGH 15, MS. GLICK CLAIMS THAT SCE&G'S RESERVE MARGIN METHODOLOGY RELIES SOLELY ON THE RELATIONSHIP BETWEEN LOAD AND WEATHER. DO YOU AGREE?

A. No. As I previously discussed, for at least 20 years, SCE&G has used what it calls the component methodology in which the three components of reserves are addressed directly. In the past, this methodology has only been used to establish a summer reserve margin. But in recent years, the need to establish a winter reserve margin has become evident. This is because winter peaks have become as large as or larger than summer peaks and because a significant amount of solar capacity is coming onto the system, which alleviates some of the summer capacity needs but none of the winter capacity needs.

Q. ON PAGE 10, LINE 17, THROUGH PAGE 11, LINE 15, MS. GLICK REPORTS THAT "REGIONAL PEER UTILITIES LIKE DUKE AND SOUTHERN COMPANY USE A DIFFERENT, MORE COMPREHENSIVE METHODOLOGY THAT BALANCES PHYSICAL RELIABILITY AND CUSTOMER COSTS." DOES SCE&G CONSIDER THE COST TO CUSTOMERS OF SUPPLYING RESERVE CAPACITY?

A. Yes, but this consideration relies on judgment. For example, as documented in Exhibit No. ___ (JML-2) of my direct testimony, SCE&G sets its reserve margin such that when the system experiences extreme summer weather or extreme winter weather, there is a 30% probability that SCE&G's supply resources will not be able to meet the resulting peak load. While at first glance this may appear high, SCE&G knows that its customers cannot afford to entirely eliminate all risk. Based on the data and its judgment, SCE&G therefore believes that setting the reserve margin at this 30% probability level strikes a reasonable and appropriate balance. I also would note the same logic that supports a 14% reserve margin for SCE&G in the summer supports a 21% reserve margin in the winter as reflected in Exhibit No. ___ (JML-2) attached to my direct testimony.

Q. WHY DOESN'T SCE&G FORMALIZE THIS BALANCE BETWEEN RELIABILITY AND COST BY EMPLOYING THE METHODOLOGY USED BY DUKE AND SOUTHERN COMPANY?

A. Duke and Southern Company use the Strategic Energy and Risk Valuation Model ("SERVM") developed by the ASTRAPE Consulting firm. Although the reserve margin studies of Duke and Southern are not publicly available and the method of estimating the customer outage cost appears to be confidential and proprietary because it has not been published to my knowledge, the SERVM methodology has been discussed publicly in other studies. Based on my review of this available information, I do not believe the SERVM model would adequately account for SCE&G's risks especially related to its summer and winter peak demands. I also question how meaningfully the model can measure the customer cost of a system outage. For example, the SERVM methodology of estimating customer outage costs appears to involve the consideration of multiple unknown variables, which would result in a wide range of outage cost values. In addition, I am aware that the Brattle Group used the SERVM model at the behest of the Electric Reliability Council of Texas ("ERCOT"). The results derived from the SERVM model indicated that the balance point between customer cost and construction cost of new plants was a reserve margin of 10.8%; however, this reserve margin did not meet ERCOT's reliability criteria of an LOLE of 1 day in 10 years. It therefore appears that SERVM does not always give a reasonable answer.

Q. ON PAGE 14, LINES 22 THROUGH 23, MS. GLICK STATES THAT SCE&G "ASSERTS THAT RESOURCES ONLY HAVE CAPACITY VALUE IF THEY ARE AVAILABLE IN BOTH SUMMER AND WINTER." DO YOU AGREE?

A. No. Resources have value whenever they are available. However, in the context of avoided cost, it is not a question of "value." The issue is what costs can be avoided by the purchase of a QF resource. SCE&G has determined that solar power incremental to the 865 MWs already under signed PPAs does not avoid capacity in its resource plan and therefore has a zero avoided capacity cost.

Q. ON PAGE 16, LINE 1, THROUGH PAGE 18, LINE 13, MS. GLICK STATES THAT THE COMPANY SHOULD HAVE INCLUDED OPPORTUNITY COSTS IN ITS REVENUE REQUIREMENTS CALCULATION. WHAT IS THE COMPANY'S RESPONSE TO THIS STATEMENT?

A. I would first note that, as part of last year's fuel proceeding, the Commission specifically found that "it is reasonable and appropriate for the Company not to consider opportunity costs in its revenue requirements calculation in that a solar QF does not have firm capacity as an intermittent resource and does not add to the Company's opportunity, if such opportunity exists, to sell firm capacity." Order No. 2017-246 at 22-23.

Regardless, the opportunity costs mentioned by Ms. Glick refer to the potential to sell available capacity in the power market and thereby increase the value of the QF capacity. In order to sell capacity to a neighboring utility, it must be firm and dependable capacity. A solar QF does not have firm capacity as it is an intermittent resource and, therefore, SCE&G could not sell solar capacity. In addition, because solar capacity is intermittent, it does not add to SCE&G's opportunity to sell firm capacity. When SCE&G purchases firm capacity to serve its customers, it passes those costs onto its customers. Similarly, when SCE&G sells firm capacity, the Company believes that the benefits of such a sale should accrue to SCE&G's customers, not to the QF. Finally, it is worth noting that if there were a lucrative market for solar capacity, the solar facility would not be selling its energy to SCE&G at SCE&G's avoided costs but instead would sell its capacity directly to interested purchasers at higher prices.

Q. ON PAGE 18, LINE 14, THROUGH PAGE 20, LINE 11, MS. GLICK SUGGESTS THAT THE COMPANY SHOULD PAY QFs A PERFORMANCE ADJUSTMENT FACTOR. DO YOU AGREE WITH HER SUGGESTION?

A. I do not agree for several reasons. First and foremost, the Commission found that "it is unreasonable to employ a PAF to the capacity payment because there is no guarantee of performance with regard to capacity from solar facilities." Order No. 2017-246 at 23.

Furthermore, Ms. Glick argues that a PAF is necessary to treat the QF capacity equally with a utility's generating units. However, I do not believe that it is reasonable or meaningful to compare the intermittent capacity of a solar QF, which only provides energy as weather permits, with the firm capacity of a more dependable generating unit such as a combustion turbine.

By way of an example, the maximum hourly output of a large solar generator on SCE&G's system in 2016 was 2,042.4 kW. However, there was only one hour in the year that the solar generator generated 2,042.4 kWs, only 6 hours where its output was above 2,000 kWs, and only 35 hours when its output was within 100 kWs of its maximum. Accordingly, this facility only generated energy near its maximum output for 0.4% of the hours for the year. Moreover, its output was above 50% of its maximum for only 18% of the hours and for 51% of the hours its output was zero.

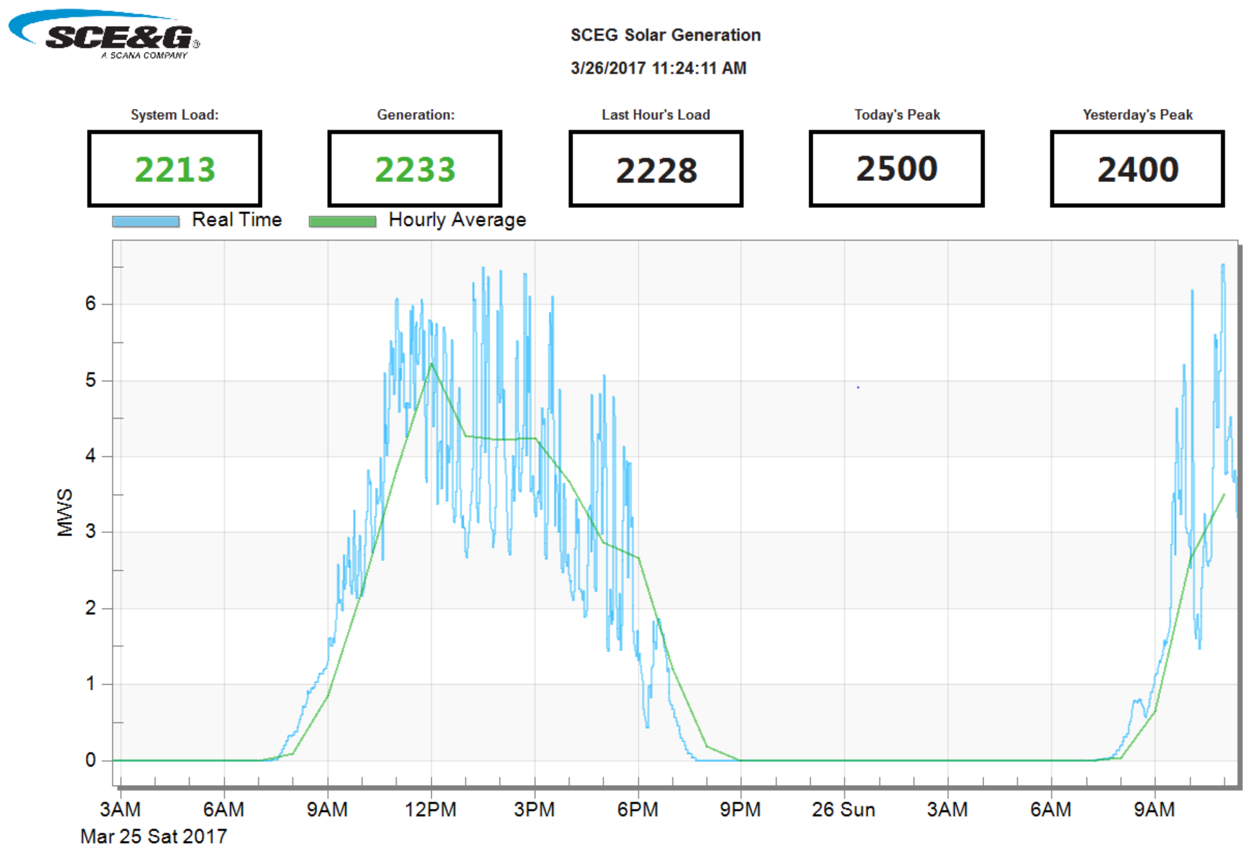
The data therefore demonstrates that this solar facility provides little, if any, firm dependable capacity to SCE&G's system which the Company can reliably call upon to serve its customers. For these reasons and those articulated in previous fuel hearings, I therefore believe it is inappropriate to apply a PAF to increase SCE&G's avoided cost rates.

Q. ON PAGE 22, LINE 11, THROUGH PAGE 23, LINE 8, MS. GLICK STATES THAT DISTRIBUTED ENERGY RESOURCES ("DERs") ALLEVIATE THE STRAIN ON THE SYSTEM DURING TRANSMISSION OR DISTRIBUTION SYSTEM PEAKS AND COULD THEREBY AVOID INVESTMENTS. DO YOU AGREE?

A. No. Again, the Commission has recognized that "[t]he Company must design its transmission and distribution system so as to provide safe and reliable electric service, even when intermittent generation sources such as solar facilities and other small QFs are not producing power." Order No. 2017-246 at 24. Ms. Glick has not identified any new evidence that would support a change from this established position.

Nevertheless, transmission lines on the SCE&G system are designed to carry up to 948,000 kW. With the NEM solar capacity distributed throughout the system, the current impact on any single transmission line is less than 1,500 kW. SCE&G's transmission planning engineers consider this level of load, which is about 0.1% of the total load, to be no more than noise on the system and it does not have any expected impact on the need for future transmission lines.

The case may be different for distribution lines which serve local loads; however, it is not clear whether the solar generators increase the strain on the line or decrease it. Although, as shown in the below graph of solar output from a recent day, the extreme fluctuation in the real-time solar output is likely to increase the strain on the distribution system.



Regardless, SCE&G's distribution engineers must plan the distribution line assuming the solar output is zero because solar is an intermittent resource. While this may change in the future as SCE&G has more experience with solar QFs on the system, SCE&G has set the avoided cost relative to transmission and distribution at zero at this time.

Q. ON PAGE 23, LINE 9, THROUGH PAGE 26, LINE 7, MS. GLICK STATES THAT OTHER ENERGY RESOURCES, SUCH AS ENERGY EFFICIENCY, RECEIVE CREDIT FOR DEFERRING OR AVOIDING TRANSMISSION AND DISTRIBUTION RESOURCES, AND RECOMMENDS THE METHODOLOGY SCE&G SHOULD USE TO CALCULATE THE VALUE OF AVOIDED TRANSMISSION AND DISTRIBUTION CAPACITY FOR DER. DO YOU HAVE ANY COMMENTS ON THESE STATEMENTS AND RECOMMENDATIONS?

A. Yes. Other energy resources, such as energy efficiency, may be credited with avoiding transmission and distribution costs. With respect to the transmission system, however, I suspect that in considering a program such as energy efficiency, the effects of which are dispersed around a system, an analysis of the localized impact will demonstrate the impact to be too small to affect the transmission system for the same reasons mentioned previously. With respect to the distribution system, energy efficiency is not an intermittent resource like a solar generator so there may be justification for an avoided cost credit.

Q. ON PAGE 26, LINE 18, THROUGH PAGE 28, LINE 9, MS. GLICK SUGGESTS THAT SCE&G INCORRECTLY CALCULATED SYSTEM LINE LOSSES ASSOCIATED WITH DERS. DO YOU AGREE WITH HER SUGGESTION?

A. No, I do not. SCCCL and SACE previously raised this issue in Docket No. 2017-2-E, but the Commission found that “the Company’s calculation of line losses is appropriate and that average transmission losses are the best estimate to use for marginal losses." Order 2017-246 at 38. The Commission also found that "the Company properly applied line losses for both energy and capacity in a manner consistent with the methodology approved in Order No. 2015-194." *Id.* Therefore, I believe Ms. Glick's suggestion is unfounded and without any basis.

Even so, the PR-1 and PR-2 rates and the 11-point NEM methodology all involve the adjustment of QF energy supplied over many hours of the year. For this reason, the use of an average loss factor is appropriate. SCE&G also has calculated system line losses for many years and believes that the estimation of losses for each hour of the year or for many incremental levels would be a burdensome enterprise that would yield little or no value. Accordingly, the Company does not agree that it is necessary to calculate line losses for every hour of the year nor for the incremental steps suggested by Ms. Glick.

Q. ON PAGE 28, LINE 10, THROUGH PAGE 29, LINE 21, MS. GLICK SUGGESTS THAT SCE&G INCORRECTLY MODELED MARGINAL LINE LOSSES. DO YOU AGREE WITH HER SUGGESTION?

A. No. The distribution system essentially is a radial system with the power flowing only on a single line. For the most part, losses are equal to what are called I^2R losses and, for I^2R losses, marginal losses are approximately equal to twice the average losses. To estimate marginal line losses on the distribution system, SCE&G therefore doubled the average line losses with which Ms. Glick agrees.

On the transmission system, however, the Company believes that marginal losses should be approximated by average losses. The transmission system is a network of sources and sinks with power lines connecting them. Power enters the network from its sources, i.e., generators, and leaves the network at sinks, i.e., substations feeding the distribution system, flowing along the path of least resistance. Thus, marginal line losses in a network will be less than those on the distribution system.

More importantly, the distance that power has to flow will depend on the loading at each source and sink and SCE&G's generation must equal its load. On the transmission network this means that power entering the network must equal the power leaving the network and each element is identified in SCE&G's transmission system computer model. To estimate marginal losses, SCE&G's analysis considered lowering the loads at each substation to effect a 100 MW decrease across the system, and then eliminating a source of energy from the Company's Hagood Unit to balance the system. Under these circumstances, the analysis showed that power had to flow a greater distance to serve the load and losses increased, meaning that average losses were greater than marginal losses. After performing several similar analyses, the Company concluded that average transmission losses are the best estimate to use for marginal losses.

Q. ON PAGE 30, LINES 1, THROUGH 14, MS. GLICK SUGGESTS THAT AVOIDED MARGINAL TRANSMISSION AND DISTRIBUTION LINE LOSSES ALSO HAVE CAPACITY IMPLICATIONS. DO YOU AGREE WITH HER SUGGESTION?

A. I agree and would note that SCE&G applies line losses for both energy and capacity as appropriate.

Q. ON PAGE 30, LINES 15 THROUGH 22, MS. GLICK STATES THAT ANY QF CONNECTED AT THE DISTRIBUTION LEVEL SHOULD BE REIMBURSED FOR TRANSMISSION-LEVEL SAVINGS AND THAT SMALL QFs AND NEM DERs SHOULD BE REIMBURSED FOR BOTH TRANSMISSION-LEVEL AND DISTRIBUTION-LEVEL SAVINGS. WHAT IS THE COMPANY'S RESPONSE TO THIS STATEMENT?

A. Payments or credits to small QFs and NEMs are subsidized by SCE&G's DER program, so reimbursement in this case is not at issue. However, the PR-1 rate for small QFs and the NEM avoided cost methodology do have loss factor adjustments. Larger QFs likely will flow power back onto the transmission system and will incur, not avoid, transmission level losses.

Q. ON PAGE 30, LINE 23, THROUGH PAGE 31, LINE 2, MS. GLICK RECOMMENDS THAT AN ADJUSTMENT SHOULD BE MADE TO THE AVOIDED COST RATES DUE TO A RESERVE MARGIN BENEFIT FROM DER RESOURCES. DO YOU AGREE WITH HER RECOMMENDATION?

A. SCE&G disagrees. The Commission previously found that "[i]t is appropriate for the Company to maintain a reserve margin to back up DERs, which are intermittent supply sources" and that "[a]ccordingly, DER resources do not result in a reserve margin benefit for the Company." Order No. 2017-246 at 38. Therefore, there is no reserve margin benefit from DER resources.

Q. ON PAGE 31, LINE 21, THROUGH PAGE 32, LINE 15, MS. GLICK STATES THAT AVOIDED ENVIRONMENTAL COSTS SHOULD BE INCLUDED IN THE NEM DISTRIBUTED ENERGY RESOURCE CALCULATION. WHAT IS THE COMPANY'S RESPONSE TO THIS STATEMENT?

A. I would again note that the Commission has found that the Company's methodology "properly account[s] for avoided environmental costs and that there are no other environmental costs that are not already included in the other specific components of the methodology." Order No. 2017-246 at 39.

In addition, Attachment A to the Settlement Agreement entered into by the parties of record to Docket No. 2014-246-E ("Settlement Agreement"), including CCL and SACE, affirmatively states that "[t]he environmental compliance and/or Utility system costs might be accounted for in the Avoided Energy component, but, if not, should be accounted for separately. The Avoided Energy component must specify if these are included." There are no environmental costs that are not already included in the other specific components of the methodology and, for this reason, SCE&G appropriately assigned a zero avoided cost value to this component.

Q. NOTWITHSTANDING THE FACT THAT CCL AND SACE ENTERED INTO A SETTLEMENT WHEREBY THEY AGREED ENVIRONMENTAL COSTS COULD BE ACCOUNTED FOR IN THE AVOIDED ENERGY COMPONENT, HAS SCE&G ALSO ANALYZED WHETHER ENVIRONMENTAL COSTS SHOULD BE SEPARATELY ACCOUNTED FOR IN THE NEM METHODOLOGY?

A. Yes. In Order No. 2017-246, the Commission directed the Company to address the cost-effectiveness of separately accounting for environmental costs in this fuel proceeding. Order No. 2017-246 at 39. In compliance with this directive, SCE&G has evaluated this issue and concluded that the time and resources necessary to separately account for these environmental costs do not result in any additional benefit to the NEM methodology. This is because performing this analysis would result in simply moving the environmental costs from the avoided energy component to the environmental cost component, with no net effect on the Total Value of NEM Distributed Energy Resources.

To demonstrate this fact, SCE&G further analyzed the avoided energy cost component and separately identified certain environmental costs. As discussed in my direct testimony, SCE&G has previously adjusted avoided energy costs to remove the cost of criteria pollutants, which is then reflected in the avoided criteria pollutants component. In addition, and for the purposes of this proceeding, SCE&G further adjusted avoided energy costs to remove other environmental costs for lime and ammonia, and to reflect the net profit resulting from SCE&G's sale of coal ash. This adjustment is reflected in the below table.

Total Value of NEM Distributed Energy Resources ($/kWh)

	Current Period	**IRP Planning Horizon (15-Year Levelized)**	**Components**
1	$0.03029	$0.02969	Avoided Energy Costs
2	$0	$0	Avoided Capacity Costs
3	$0	$0	Ancillary Services
4	$0	$0	T & D Capacity
5	0.00008	$0.00008	Avoided Criteria Pollutants
6	$0	$0	Avoided CO_2 Emission Cost
7	$0	$0	Fuel Hedge
8	$0	$0	Utility Integration & Interconnection Costs
9	$0	$0	Utility Administration Costs
10	$0.00041	$0.00041	Environmental Costs
11	$0.03078	$0.03018	Subtotal
12	$0.00251	$0.00246	Line Losses @ 0.9245
13	$0.03329	$0.03264	**Total Value of NEM Distributed Energy Resources**

As this table reflects, while it is possible to separately account for environmental costs, there is no net change to the Total Value of NEM Distributed Energy Resources reflected in my direct testimony. Accordingly, undertaking this exercise requires the Company to devote additional time and resources and incur additional costs related to the fuel proceeding with no corresponding or substantial benefit. The Company therefore believes that separately accounting for these environmental costs is not cost effective.

Q. IN THE ABOVE TABLE, THE COST FOR AVOIDED CRITERIA POLLUTANTS APPEARS TO HAVE CHANGED FROM THAT PRESENTED IN YOUR DIRECT TESTIMONY. CAN YOU EXPLAIN THE REASON FOR THE CHANGE?

A. Yes. In analyzing the cost effectiveness of separately accounting for environmental costs, the Company determined that the value of avoided criteria pollutants cost component reflected in my direct testimony, which was \$0.00004, was incorrect. Instead, the value of this component should be \$0.00008, with a corresponding reduction in the avoided energy cost component. While the values for avoided energy costs and avoided criteria pollutants contained in the above table have been corrected and should be adopted by the Commission in this proceeding, this correction has no net effect on the Total Value of NEM Distributed Energy Resources.

REBUTTAL TO TESTIMONY OF DR. JOHNSON

Q. WITH RESPECT TO DR. JOHNSON'S TESTIMONY, PLEASE EXPLAIN HOW YOU ORGANIZE YOUR RESPONSES.

A. In the same manner I responded to Mr. Horii's and Ms. Glick's testimony, my rebuttal testimony sequentially addresses the issues raised by Dr. Johnson as they appear in his direct testimony. I also would note that Dr. Johnson's testimony appears to primarily restate the suggestions and recommendations set forth in his testimony filed in the Company's 2017 fuel proceeding, Docket No. 2017-2-E, and which were rejected by the Commission in Commission Order No. 2017-246.

Q. ON PAGE 11, LINE 4, THROUGH PAGE 23, LINE 18, DR. JOHNSON DISCUSSES PURPA. DO YOU HAVE ANY COMMENTS ON THIS TESTIMONY?

A. I only would note that Dr. Johnson failed to cite an important provision of PURPA. Specifically, and as I mentioned previously, PURPA regulations provide that "[n]othing … requires any electric utility to pay more than the avoided costs for purchases" from QFs. 18 C.F.R. §292.304(a)(2).

Q. ON PAGE 31, LINE 4, THROUGH PAGE 33, LINE 19, DR. JOHNSON STATES THAT QF RATES SHOULD BE SET EQUAL TO THE COST OF HAVING THE UTILITY BUILD AND OPERATE ITS OWN GENERATING UNITS. DO YOU AGREE WITH HIS SUGGESTION?

A. I do not. First, the Commission rejected this recommendation in Order No. 2017-246 and found that "[t]he methodology approved by the Commission in Order No. 2016-297 sets forth the proper manner in which to determine the Company's actual avoided cost." Order No. 2017-246 at 28.

However, Dr. Johnson also states that "… the public interest is best achieved by establishing rates that leave ratepayers indifferent …" (page 33, lines 9-10). This implies that QF rates should not be set either too low or too high, and also should not be set to the utility's cost to build. Instead, QF rates should be set equal to the utility's actual avoided cost. Under any other circumstances, ratepayers will not be indifferent as Dr. Johnson recommends.

Q. ON PAGE 34, LINE 1, THROUGH PAGE 35, LINE 15, DR. JOHNSON RECOMMENDS THAT AVOIDED COSTS SHOULD BE EVALUATED ON A LONG-TERM BASIS. WHAT COMMENTS DO YOU HAVE ON THIS RECOMMENDATION?

A. I simply would note that the rates in PR-2 reflect the Company's long-term avoided costs.

Q. ON PAGE 40, LINES 12 THROUGH 21, DR. JOHNSON STATES THAT SCE&G ANALYZED DIFFERENT GENERATION EXPANSION PLANS AND THE ASSOCIATED ENERGY COSTS BUT "DOES NOT DEVELOP A COMPREHENSIVE, DETAILED ANALYSIS OF ITS REVENUE REQUIREMENT" AND DOES NOT SHOW THE CORRESPONDING REVENUE REQUIREMENT FOR THESE EXPANSION PLANS OR THAT THIS APPROACH IS CONSISTENT WITH MINIMIZING REVENUE REQUIREMENTS. DO YOU AGREE?

A. No. SCE&G has explained that, for Rate PR-2, incremental solar beyond the 865 MWs of solar capacity already under contract does not alter its resource plan and, therefore, the difference in revenue requirement is zero. A comprehensive, detailed revenue requirement is not needed for the calculation of avoided costs which are based on incremental effects.

Q. ON PAGE 46, LINE 7, THROUGH PAGE 48, LINE 1, DR. JOHNSON SUGGESTS THAT THERE ARE CERTAIN DISADVANTAGES TO USING PROSYM TO MODEL PRODUCTION COSTS. DO YOU AGREE WITH HIS SUGGESTION?

A. I disagree. As recognized by the Commission in Order No. 2017-246, it is appropriate for SCE&G to use PROSYM, which is a standard production costing model used at many utilities and used by SCE&G for many years. Order No. 2017-246 at 29.

Q. ON PAGE 48, LINE 2, THROUGH PAGE 51, LINE 5, AND PAGE 120, LINE 11, THROUGH PAGE 127, LINE 5, DR. JOHNSON STATES THAT HE DEVELOPED BENCHMARK AVOIDED ENERGY AND CAPACITY COST ESTIMATES USING THE PROXY UNIT METHOD BASED ON HYPOTHETICAL NUCLEAR, COMBINED-CYCLE, AND COMBUSTION TURBINE PLANTS. DO YOU HAVE ANY COMMENTS ON THESE ESTIMATES?

A. Yes. I would first note that the Commission has rejected this recommendation previously and found that Dr. Johnson's "recommendation to calculate avoided costs based on the utility's cost to build its own generating facilities is inappropriate" and that "using the Proxy method as recommended by Witness Johnson would not add further accuracy to the estimate of SCE&G's avoided costs." Order No. 2017-246 at 30.

Furthermore, as Dr. Johnson points out, one advantage of the Proxy Method is that it is simple to calculate and easy for others to understand. In his discussion, however, Dr. Johnson leaves out the most important aspect of the method—how it is relevant. Specifically, he does not explain how the cost to construct these proxy plants relate to the costs SCE&G would avoid through a QF purchase, i.e., the avoided cost rates that leave ratepayers indifferent. Ratepayers would not be indifferent to the choice of paying the different capacity costs of a nuclear plant, a combined-cycle plant, or a combustion turbine. Rather, given the choice, ratepayers would choose to pay the capacity cost of the least expensive generating facility—a combustion turbine.

Q. ON PAGE 51, LINE 6, THROUGH PAGE 77, LINE 8, DR. JOHNSON ESTIMATES VARIABLE ENERGY COSTS AND MAKES CERTAIN ASSUMPTIONS REGARDING NATURAL GAS PRICES. DO YOU AGREE WITH THESE ESTIMATES AND ASSUMPTIONS?

A. I agree that future natural gas prices are uncertain. However, I also would point out that the Commission has previously found SCE&G's methodology to estimate future natural gas prices is reasonable and consistent with the methodology approved in Order No. 2016-297.

In addition, it is my opinion that a simple trend line using historical gas prices cannot be used with confidence to project future prices as a result of the recent advancements in fracking technology. To forecast natural gas prices, SCE&G uses the price of futures contracts traded on the NYMEX over the next three years and then applies a growth rate to project prices over the longer term. The NYMEX prices have been used in SCE&G's fuel hearings for many years because they represent publicly available information and also are good indicators of gas prices in the short term.

Q. ON PAGE 59, LINE 6, THROUGH PAGE 73, LINE 9, DR. JOHNSON DISCUSSES SCE&G'S DECISION TO ABANDON THE NEW NUCLEAR UNITS AND SUGGESTS THAT THE COMPANY DID NOT CONSIDER THE BENEFITS OF A BALANCED GENERATING PORTFOLIO IN DEVELOPING ITS PROPOSED QF RATES. DO YOU AGREE?

A. No. SCE&G is aware of its resource mix and believes that the addition of 865 MWs of solar capacity helps to have a more balanced portfolio. However, SCE&G, like most utilities, believes that gas fired generation is the most economical choice of dispatchable generation for the next few years.

Q. ON PAGE 82, LINE 1, THROUGH PAGE 88, LINE 6, DR. JOHNSON ADDRESSES THE PROPOSED CHANGES TO THE AVOIDED CAPACITY RATES FOR SOLAR AND TO RATE PR-1 AND PR-2. WHAT IS YOUR RESPONSE?

A. Dr. Johnson appears to be making three primary points which I will address individually. First, he states that not compensating QFs for their reliability benefits is intensely and unlawfully discriminatory. As I explained before, in the context of avoided costs, the issue is not what benefits or value QFs will receive. Rather, the issue is what capacity costs are being avoided. Simply put, if no capacity costs are avoided, then the avoided cost is zero.

Second, Dr. Johnson objects to limiting Rate PR-2 to solar projects and asserts that this would establish an arbitrary distinction between solar and non-solar technologies. However, this distinction is hardly arbitrary since SCE&G only has solar projects requesting avoided cost rates and the determination of avoided cost depends strongly on the type of project under consideration. When a non-solar project seeks to enter into a PPA with SCE&G and requests its avoided costs, some specification has to be made as to what the project's power producing characteristics will be. Dr. Johnson also specifically mentions solar combined with battery storage. As Witness Raftery states in his direct testimony, SCE&G will issue an RFP to collect information on solar plus battery projects with the intention of having a project or two placed online. SCE&G then will be better able to analyze the impacts of these types of projects on its system.

Finally, Dr. Johnson objects to SCE&G's proposal to update Rate PR-2 on an as-needed basis. SCE&G believes it is sufficient to have a scheduled update of the PR-2 rate once a year at the fuel hearing with the option, but not the requirement, to update it more frequently on an as needed basis.

Q. ON PAGE 88, LINE 7, THROUGH PAGE 95, LINE 18, DR. JOHNSON STATES THAT STRONGER, MORE PRECISE PRICE SIGNALS SHOULD BE REQUIRED FOR COMPETITIVE INVESTMENT DECISIONS. DO YOU AGREE?

A. No. PURPA requires SCE&G to purchase the power produced by any and all QFs that desire to sell power at the Company's avoided cost. SCE&G is prohibited by law from turning away less efficient QFs so the use of avoided costs is not a good vehicle to enhance competitive markets.

Q. ON PAGE 96, LINE 1, THROUGH PAGE 115, LINE 8, DR. JOHNSON DISCUSSES TYPES OF COSTS AND SUGGESTS THAT PRICES SHOULD INCLUDE A MARKUP TO PROVIDE A MECHANISM FOR JOINT AND COMMON COSTS. DO YOU AGREE?

A. No. A markup suggests that SCE&G should pay more than its avoided cost which is contrary to the intent of PURPA. If SCE&G avoids any joint and common costs through the purchase of power from a QF, then those costs should be reflected in its avoided cost rate but without a markup. Dr. Johnson also discusses fixed costs across time suggesting that a combined-cycle generating facility that provides capacity in the winter will also provide capacity in the summer. However, this scenario demonstrates why the avoided capacity cost for solar is zero. If SCE&G has to build a combined-cycle unit to meet its winter peak, but which also satisfies the need for summer capacity, then the fixed costs are incurred. In contrast, adding solar capacity, which only has an impact on capacity in the summer, does not avoid any of those fixed costs.

Q. ON PAGE 115, LINE 9, THROUGH PAGE 120, LINE 10, DR. JOHNSON STATES THAT SOLAR AND NON-SOLAR GENERATORS SHOULD NOT BE PAID DIFFERENT PRICES. WHAT IS YOUR RESPONSE?

A. QFs should be paid their avoided cost. Solar QFs all have similar characteristics and avoid costs at approximately the same rate. For this reason, providing a standard rate for solar QFs, such as PR-2 and PR-1, is efficient and reasonable. On the other hand, non-solar QFs may have significantly different characteristics from other non-solar QFs; therefore, these projects should be considered on an individual basis and separate, specific PPAs should be negotiated for each such project. And, even though it is not possible to accurately estimate the impact small non-solar QFs (under 100 kW) have on the system, the impact they do have is so small that establishing a separate rate for these facilities would be meaningless. Rather, it is more appropriate to have a standard rate for these types of projects such as the Company's Rate PR-1.

CONCLUSION

Q. DO YOU HAVE ANY FINAL COMMENTS REGARDING THE ISSUES RAISED IN MR. HORII'S, MS. GLICK'S, AND DR. JOHNSON'S DIRECT TESTIMONIES?

A. Yes. Notwithstanding Mr. Horii's, Ms. Glick's, and Dr. Johnson's characterizations and recommendations, SCE&G has faithfully complied with its prior practices and with the methodology approved by the Commission in Order No. 2016-297 in determining the Company's avoided costs. SCE&G also has fully complied with the methodology for calculating the components of value for NEM Distributed Energy Resources as agreed to by the parties of record in Docket No. 2014-246-E and approved by the Commission in Order Nos. 2015-194, 2016-297, and 2017-246. While Mr. Horii, Ms. Glick, and Dr. Johnson appear to recommend that SCE&G alter these methodologies, the Company believes it is reasonable and prudent to continue abiding by the terms of the Settlement Agreement and methodologies long-recognized and previously approved by the Commission. Therefore, I respectfully request on behalf of SCE&G that the Commission 1) approve the Company's proposed PR-1 and PR-2 Rates; 2) approve the total value of NEM Distributed Energy Resources; 3) approve the costs incurred by the Company in providing DER programs during the Review Period as being reasonable and prudent; and 4) find that the Company's fuel purchasing practices were reasonable and prudent for the Review Period.

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes.

Exhibit No. ___ (JML-5)

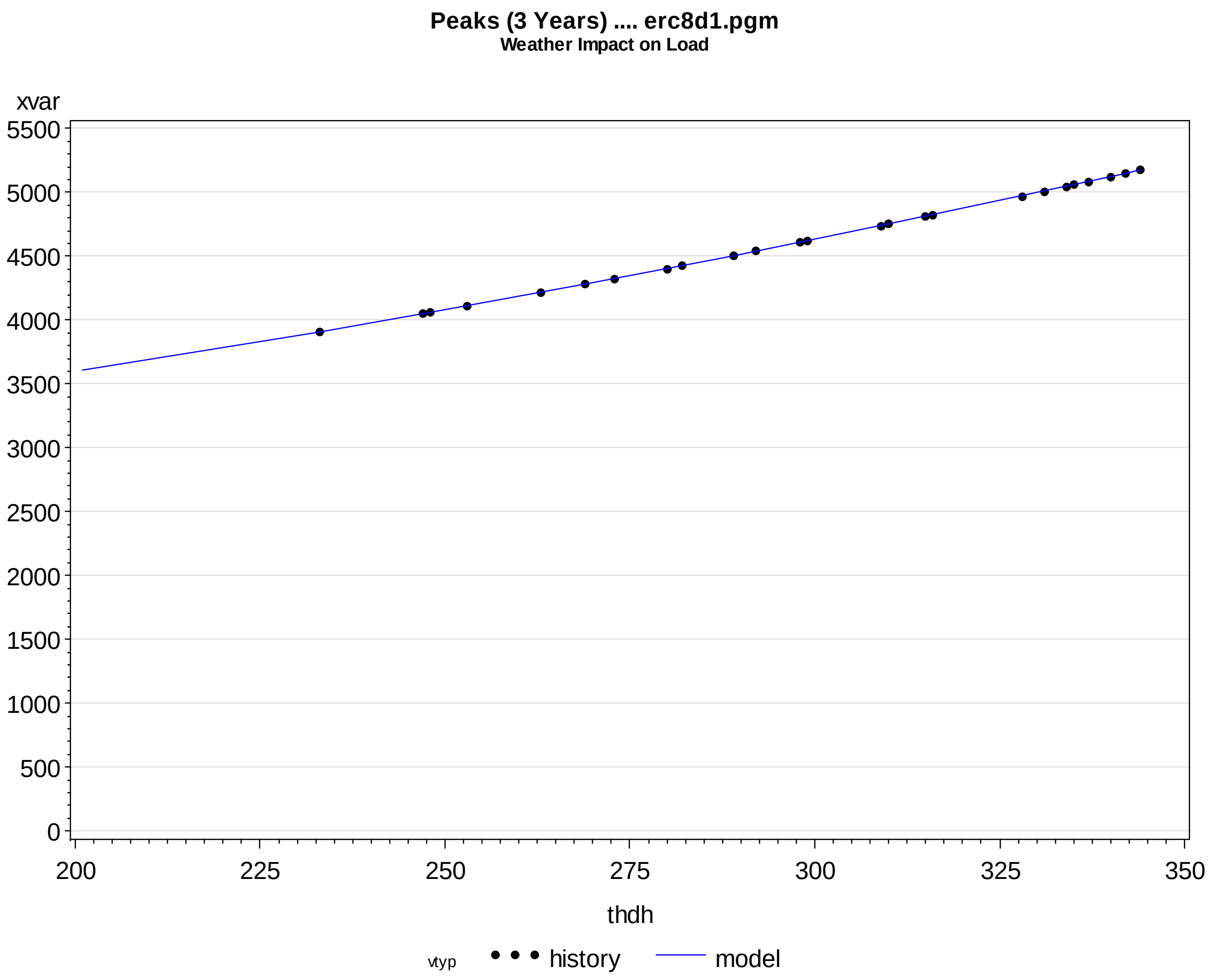


Exhibit No. ___ (JML-6)

The REG Procedure
Model: MODEL1
Dependent Variable: mxload

Number of Observations Read	83
Number of Observations Used	56
Number of Observations with Missing Values	27

Analysis of Variance

Source	DF	Sum of Squares	Mean Square	F Value	Pr > F
Model	6	8180115	1363353	96.43	<.0001
Error	49	692805	14139		
Corrected Total	55	8872920			

Root MSE	118.90698	R-Square	0.9219
Dependent Mean	3833.51786	Adj R-Sq	0.9124
Coeff Var	3.10177		

Parameter Estimates

Variable	DF	Parameter Estimate	Standard Error	t Value	Pr > |t|	Variance Inflation
Intercept	1	1747.32576	153.99535	11.35	<.0001	0
ihol	1	-647.15132	123.05644	-5.26	<.0001	1.05189
wkend	1	-436.10939	35.39243	-12.32	<.0001	1.16280
thdh	1	9.39066	0.64099	14.65	<.0001	1.09533
jan	1	109.05308	47.81469	2.28	0.0269	2.19160
feb	1	154.37914	49.20293	3.14	0.0029	2.02718
nov	1	-141.88750	64.24746	-2.21	0.0319	1.56398

	Historical Date	Historical HDH	Estimated Peak
1	23-Jan-91	280	4486
2	20-Dec-91	282	4395
3	15-Mar-93	292	4489
4	19-Jan-94	340	5049
5	9-Feb-95	335	5048
6	5-Feb-96	344	5132
7	20-Dec-96	310	4658
8	13-Mar-98	289	4461
9	6-Jan-99	337	5021
10	27-Jan-00	299	4664
11	3-Jan-01	328	4937
12	8-Jan-02	247	4176
13	24-Jan-03	342	5068
14	29-Jan-04	263	4326
15	24-Jan-05	315	4814
16	10-Feb-06	253	4278
17	6-Feb-07	233	4090
18	4-Jan-08	316	4824
19	21-Jan-09	289	4570
20	11-Jan-10	309	4758
21	14-Jan-11	310	4767
22	4-Jan-12	298	4655
23	18-Feb-13	248	4231
24	7-Jan-14	334	4993
25	20-Feb-15	331	5010
26	19-Jan-16	273	4420
27	9-Jan-17	269	4382